ACCESSION #: 9509260080
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Dresden Nuclear Power Station, Unit 3 PAGE: 1 OF 13

DOCKET NUMBER: 05000249

TITLE: Unit 3 Scram From Main Turbine Stop Valve Closure Due to
Turbine Trip On High Vibration Caused By Out of
Specification Turbine Blade Material
EVENT DATE: 05/28/95 LER #: 95-008-01 REPORT DATE: 09/22/95

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: N POWER LEVEL: 000

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR
SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
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COMPONENT FAILURE DESCRIPTION:
CAUSE: B SYSTEM: SD COMPONENT: SEAL MANUFACTURER: X999
X IG RE R220
B SD P I075

REPORTABLE NPRDS: YES
YES
YES

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On May 28, 1995, at 0923, during steady state power operation at
approximately 2527 MWT, Unit 3 scrammed from Main Turbine Stop Valve
closure due to Main Turbine High vibration. Journal Bearing 7 on the C
Low Pressure (LP-C) Turbine experienced radial vibration displacement of
14.4 MILS, exceeding the high vibration trip setpoint of 10.0 MILS. The
high vibration was caused by the failure of a blade in the LP-C Turbine
Rotor. Subsequent to the scram, a feedwater transient was experienced
which resulted in water entering the High Pressure Coolant Injection
steam line. The root cause of the Turbine blade failure was fatigue

fracture of the stellite shield due to an out of specification grade of materials used. The root cause of the Feedwater Control System failure was a design deficiency of the control logic. Corrective actions included replacement of the failed blades and changes to the feedwater control system logic initiation points. The safety significance of this event was evaluated and determined to be moderate.

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END OF ABSTRACT

EVENT IDENTIFICATION:

Unit 3 Scram From Main Turbine Stop Valve Closure Due to Turbine Trip on High Vibration Caused By Out of Specification Turbine Blade Material

A. PLANT CONDITIONS PRIOR TO EVENT:

Unit: 3 Event Date: 05/28/95 Event Time: 0923

Reactor Mode: N Mode Name: Run Power Level: 100%

Reactor Coolant System Pressure: 1004 psig

B. DESCRIPTION OF EVENT:

On May 28, 1995, at 0923, during steady state power operation at approximately 2527 MWT, Unit 3 scrammed from Main Turbine Stop Valve [TA] closure due to Main Turbine High vibration [IT]. Journal Bearing 7 on the C Low Pressure (LP-C) Turbine experienced radial vibration displacement of 14.4 MILS, exceeding the high vibration trip setpoint of 10.0 MILS. No prior indication of trouble with the Main Turbine vibration level was experienced.

Reactor Vessel water (vessel) level remained at (+)31 inches for about 1 second after the reactor scram signal was received and then rapidly descended to a level of (-)18 inches (below instrument zero). This level decrease occurred over a period of about 3 seconds due to normal mass inventory shift in the vessel from core void collapse. At time (+)4 seconds, downcomer level started to recover due to mass addition from the two operating (A and C) Reactor Feed Pumps (RFP) [SJ], pumping at approximately 9.4 Mlbs/hr. At (+)8 seconds the 3D Condensate Booster pump [SD] automatically started to maintain auction pressure for the RFPs. At time (+)12 seconds the Nuclear Station Operator (NSO), seeing the vessel level recovering to the Reactor Level Setdown Setpoint of (+)15 inches and the level still trending up, properly elected to secure the C RFP by manually tripping the pump. At approximately the same time, the Feedwater Level Control System transferred to the flow control mode of operation, with the A RFP supplying in excess of 6Mlb/hr to the Vessel. After an initial decrease in indicated vessel level due to closure of the Turbine Bypass Valves (due to steam void collapse), level began to rapidly increase.

At (+)41 seconds the vessel level reached (+)20 inches (flow control level setpoint) at which time the NSO began to manually close the B Feed Water Regulation Valve (FWRV). However, pressure indication from the A RFP discharge header indicates that the FWRV(s) (A and/or B) did not begin to close until (+)47 seconds and (+)32 inches level. From time (+)23 seconds to (+)55 seconds, vessel level rapidly increased at a rate of about 1.75-2.0 inches/second, until the high level RFP trip setpoint was reached (+)48 inches at time (+)55 seconds. When the A RFP tripped, the rate of level rise decreased to about 0.34 inches/second.

Indicated vessel level continued to rise until the (nominal) lower lip elevation ((+)55 inches indicated) of the High Pressure Coolant Injection (HPCI) [BJ] and Isolation Condenser [BL] nozzles were reached at time(+)65 seconds. The vessel level continued to increase, going off scale (60 inches) high on all operating

instruments at time (+)90 seconds to (+)200 seconds. Data from the upper wide range level column indicates that the vessel level continued to rise another 5 inches over the 9+ minutes before subsiding from inventory loss due to steam flow to the Turbine Bypass Valves and other Unit auxiliary loads. Water entered the HPCI and Isolation Condenser steam nozzles during this period. The HPCI Turbine Drain Pot level high alarm was received in the Control Room (CR) at time (+)19 minutes and cleared at (+)41 minutes.

Other problems identified during this event:

The Steam Jet Air Ejectors (SJAE) [SH] were manually isolated approximately 20 minutes after the scram without proper communication. The Field Supervisor (FS) was in the CR and was told by the NSO that an RFP needed to be started, 3-way (repeat back) communication was used. The FS told the NSO and Unit Supervisor that after checking the RFP he would also valve out the SJAEs, but no 3-way communication was used. The FS went out and chocked on the RFP for the NSO and it was started. The FS then went to the SJAEs and valved them out, but did not notify the CR prior to doing so. The NSO, seeing the CR panel indication that the SJAE had isolated, contacted the FS. The Unit NSO notified the FS that the SJAEs should not have been isolated. The FS then restored the SJAEs.

Following the scram, 4 Intermediate Range Monitors (IRM) [IG] (monitors 13, 14, 15 and 16) exhibited erratic indication in the CR, until approximately 1700 on May 28, 1995. Resetting of the scram was delayed due to the IRM erratic indication.

The 3-203-1A Main Steam Isolation Valve (MSIV) [JM] then showed a dual indication on the CR Switch indicating lights. Operator response to this indication was to isolate the A main steam line. No valid Group I isolation signal was received.

Upon the automatic trip of the A RFP, the 3A and 3C Condensate Booster Pumps (CBP) experienced seal failure.

During a test run of the 3A CBP, steel and brass particles were identified in the outboard bearing oil sight glass. Upon disassembly of the CBP it was discovered that the impeller wear rings had loosened and failed to perform their function. The other three CBPs were inspected, and 3B and 3C CBPs were found to be in the same condition. The 3D CBP was found to be in satisfactory condition. The impeller wear rings of the four Condensate Pumps (CP) were also inspected and found to be in satisfactory condition.

C. CAUSE OF EVENT:

This report is being submitted in accordance with 10CFR50.73(a)(2)(iv), which requires reporting of any event that results in an unplanned manual or automatic actuation of any engineered safety feature, including the Reactor Protection System.

Main Turbine Trip:

The high vibration was caused by the failure of a last stage blade in the LP-C turbine rotor. Visual inspections revealed approximately 8" of one blade missing. Metallurgical analyses revealed that a fatigue fracture started in the stellite erosion shield, which is welded to the leading edge of the blade, and propagated halfway across the width of the blade. The blade piece then tore off from mechanical overload and exited to the condenser below.

An investigation team consisting of Station and corporate Engineering Support personnel was assembled. This team reviewed the material properties, chemical compositions, fabrication and installation methods and tolerances, design operational conditions and fracture surface evidence. It was determined that the failed blade was manufactured by Asea Brown Boveri (ABB), which had reverse engineered replacement blades based upon original Equipment Manufacturer (OEM) General Electric blades.

Metallurgical analysis determined that most of the reverse engineered blades did not contain the correct specification grade (6B) of stellite material in the erosion shields as contained in the original GE blades. It was also found that the internal geometries, ie., thicknesses of the stellite and base metal of the failed blade were significantly different than the original design. However, these differences were analyzed and determined not to be a cause of the cracking. Additional factors, such as defects or residual stresses resulting from the welding process qualified for stellite 6B and used on non-6B stellite also contributed to the crack initiation. once initiated, these cracks may propagate based on their location on the blade and service time. There was no evidence on the fracture surface to suggest that foreign object impact or stress corrosion played a role in the failure.

The root cause of the turbine blade failure was the use of an out of specification grade of stellite which was more brittle than the stellite used in the original blades, which resulted in the blades being more susceptible to fatigue cracking.

The original GE rotor overhaul inspection plan included a recommendation to perform penetrant (PT) inspections on the stellite erosion shields when the rotor magnetic particle tests are performed. The overhaul inspection program provided with the ABB rotors did not include penetrant inspections.

Level Transient:

The vessel level and feed water flow transient were normal for a scram from high power until the C RFP was manually tripped by the NSO. When the C RFP was tripped, and with vessel level below (+)20 inches and the A RFP flow rapidly increasing to 5.6 Mlbs/hr, the Feedwater Control System changed control modes from level control to flow control. The shift from Level to flow control mode was automatic and consistent with the design setpoints in the system. Analysis of the Sequence of Events Recorder (SER) [IQ] and the Transient Analysis Display System (TADS) [IP] data shows that the subsequent Feedwater Control System operation was not satisfactory for most of the remainder of the post scram level/feed flow transient.

At the time of the transition from level to flow control, the B FWRV was in manual at some intermediate position and the A FWRV was opening in automatic control. When in the Flow Control mode, both valves will follow commands from the Flow Controller. The Flow Controller will command both valves to move to a

position where feedwater flow will match the set point installed in the Controller. For a single pump, the flow set point is 4.9 Mlbs/hr. Hence, with a flow control initiation setpoint of 5.6 Mlbs/hr, feedwater flow should have decreased to match the setpoint. However, the FWRVs ramped open rather than closing to meet the setpoint. Feedwater flow rapidly increased to a value in excess of 6.0 Mlbs/hr. ((+)12 seconds), thus accelerating the rate of level rise.

The Feedwater Control System remained in the flow control mode of operation until approximately (+)40 seconds when a vessel level of (+)20 inches was attained. At this time the Feedwater Control System is believed to have automatically reverted to level control mode. The NSO began closing the B FWRV; however, the TADS trace for the RFP discharge header pressure does not indicate that either the A (automatic) or B FWRV started closed until time (+)47 seconds and (+)32 inches level. The delay in valve closure caused the transient level to reach the automatic RFP trip setpoint of (+)48 inches at time (+)55 seconds.

After the A RFP automatically tripped, the rate of level rise was drastically reduced to about 0.3 inches/second. Concurrent with the time of the A RFP trip, the Reactor Recirculation Pumps [AD] were running back to their minimum speed in accordance with automatic action of the Low Feedwater Flow Run Back Interlock. This action of reduced Core Recirculation flow causes a swell in the Vessel downcomer which correlates to an increase in indicated level.

Analysis of feedwater system performance has determined that the system did not perform properly in the following manner:

Feedwater level Setpoint Setdown did not actuate immediately upon receipt of the scram signal as per design. Proper operation of this feature would have resulted in an immediate decrease in feedwater flow upon receipt of a scram signal.

Flow control mass flow rate for one RFP is 4.9 Mlbs/hr; however, the A RFP maintained a flow rate greater than 6 Mlbs/hr after the C RFP was manually tripped.

The Feedwater Control System did not respond to vessel level rising above the flow control reset setpoint for approximately 5 seconds.

The root cause of the Feedwater Control System failure was a design deficiency of the control logic initiation points.

Contributing cause: the previous corrective actions implemented to prevent reactor level transients after a scram were insufficient. (reference LER 94-005/050237, 93-014/050249, 92-021/050249, 92-025/050249)

SJAE Isolated:

The root cause of the SJAEs being isolated is due to lack of three way communication between the Unit NSO and the FS prior to removing the SJAEs, which is contrary to Operations standards and Management's expectations. The FS was concentrating on the numerous jobs and tasks that are required after a Reactor scram and the call back to the CR was not performed.

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Erratic IRM Response:

Upon inspection of the erratic indicating IRMs 13-16, IRMs 13 and 16 were found with water in the connector area. No anomalies were identified on IRMs 14 and 15.

The water intrusion into the connectors for IRMs 13 and 16 lowered resistance and provided additional conduction paths which generates spurious signals in the IRM logic. The root cause of the water intrusion has not been determined and will require further troubleshooting and evaluation.

Performance history of IRMs show that some IRM detectors exhibit sporadic signals during temperature changes (vessel cooldown) in the high temperature region. upon inspection of IRMs 14 and 15 no additional problems were found. The spiking of IRMs 14 and 15 is attributed to the temperature change during Unit cool down, between 500 and 400 degrees F. The erratic behavior in limited to a narrow range of temperature and presently does not effect operability.

3-203-1A MSIV Dual Indication:

On May 30, 1995, a Drywell entry was made to inspect the A inboard (3-203-1A) MSIV. During the inspection, it was found that there was insufficient wipe of the 3-203-1A MSIV Limit Switch arm on the 1A Limit Switch. It is believed that the Limit Switch activated during the scram, but the valve remained open. The root cause of the 3-203-1A MSIV dual indication is insufficient wipe of the 1A Limit Switch due to improper Electrical Maintenance Department work practices. It is believed that the improper setpoint adjustment was installed during the last adjustment of the 3-203-1A MSIV during the previous refueling outage.

Condensate Booster Pumps:

Sudden pressure changes, and overpressurization of the mechanical seal will cause changes in the geometry of the sealing gap. Increasing pressure will cause the faces to rotate inwards, resulting in outside diameter and a diverging sealing gap. As the seal runs in this condition, the carbide face rapidly wears and allows for small particles (dirt) contained in the water to enter the face contact area. When the pressure is lowered the seal faces return to their original shape. This creates a sealing gap which allows for higher leakage rates.

The root cause of the failure is the lack of an automatic control of the pressurization of the RFP suction line when all of the operating RFPs trip.

When the operating RFPs tripped as a result of the scram, the CBPs began operating in a dead head condition. The temperature of the pump internals began to rise very rapidly. Because of the smaller mass and the higher thermal conductivity, the brass ring heated at a faster rate than the impeller. The temperatures exceeded the 250 Degrees F shrink fit temperature, allowing the ring to loosen on the impeller. This also allowed the set screws to loosen. The differential pressure caused the ring to move sideways until the set screws were barely engaging the edge of the impeller. At this time the ring expanded enough to contact the casing ring causing a shearing force that was enough to shear the

remaining engagement of the set screws permitting the ring to seize to the casing ring and rotate against the impeller until the pump was stopped.

D. SAFETY ANALYSIS:

Upon receipt of the Turbine bearing high vibration signal, the Turbine trip and resultant Reactor scram took place as per design. Receipt of the Turbine Stop Valve closure caused a sudden increase in Reactor Vessel pressure which was controlled by rapid opening of the Turbine Bypass Valves. The Turbine Stop Valve closure took place in order to protect the Turbine and lessen the affects of the pressure increase on the Reactor Vessel and fuel. The limiting factor in a Turbine trip from power is the effect on the fuel cladding safety limit. operating MCPR limits are imposed to preclude violation of this limit. A Turbine trip from power is analyzed in section 15.2.3 of the UFSAR as bounded by a trip without bypass availability. Since Turbine Bypass Valves were available during this event, there is not considered to be any challenge to fuel integrity.

The level transient which was experienced during this event resulted in putting water in to the HPCI steam supply lines. At the time this event occurred, vessel level was in excess of the Reactor Water Level high level HPCI Turbine trip setpoint ((+)48 inches), thus, preventing an automatic or manual start of the HPCI system. The water was drained out of the HPCI steam supply lines by the action of the HPCI system Drain Pots per design. During the 22 minutes the Inlet Drain Pot Alarm was active, Reactor water level was always greater than the (-)59 inch HPCI initiation setpoint.

All of the UFSAR evaluations were based on vessel swell after a line break. Although the situation described above is different from the standpoint of initiating event (vessel swell vs. level transient) the descriptions of what happens when water does enter the line is applicable since the results are the same. In addition to line break swells there is an evaluation on effects of gross carryover on the HPCI turbine. It states that it is difficult if not impossible to predict whether the HPCI turbine is capable of continued operation while ingesting slugs of water. This is due to the fact that it is extremely difficult to quantify the water in the lines, evident by the use of the term slug. The evaluation on the gross carryover did not provide any information on the operability of the system during the event.

Although approximately 300 gallons of water passed through the steam line, it is believed that plant conditions related to the HPCI system observed during the event were indicative of two phase flow. It took 19 minutes for the alarm to come in after water went over the HPCI line (55 inches). The vessel temperature is approximately 545 degrees F (based on moderator temperature) with feedwater temperature at approximately 340 degrees F. The HPCI line would be 545 degrees F at the vessel and decrease the farther away from the vessel. What this indicates is that as the water entered the line, flashing would occur down the length of the pipe. Section 6.3.3.1.3.2.1.2 of the UFSAR discusses moisture carryover for a small break. The quantity of water evaluated for this event was postulated to be 75 pounds. Section 6.3.3.1.3.2.1.3 of the UFSAR is more applicable since it evaluates larger breaks and a higher carryover. It states that solid slugs would still not be possible to form. This would be due to the flashing which would increase mixture quality and provide turbulent mixing.

There is no evidence that this phenomena did not occur during the May 28 event. Had there been any slugs formed, given the quantity of water involved and average speed of 18 ft/min (350 ft of pipe/19 min (time for alarm to come in)), there should have been some evidence of the resultant force, such as restraint damage. An Engineering walkdown of the accessible restraints of the affected line did not find any evidence of damage. This indicates that the event that occurred on May 28 was bounded by the two phase flow discussion contained in the UFSAR. It can therefore be concluded that slugs did not occur and the HPCI system was operable and would have been able to perform its design function.

Water intrusion into the Isolation Condenser steam line would drain down to the condensate leg. This would increase the level in the condensate leg, with minimal impact on the system operation or performance.

In addition to the HPCI and Isolation Condenser Systems, the Automatic Depressurization System (ADS) was available to reduce the Vessel pressure to allow the Core Spray [BM] or Low Pressure Coolant Injection (LPCI) [BO] to provide the needed make-up inventory during this event.

The isolation of the SJAEs, without proper communication, had minimal impact on the plant response to this transient. This event took place several minutes after the turbine trip and scram. Reactor pressure was able to be controlled during this time period using the Turbine Bypass Valves. However, additional indication and required actions in the CR challenges the Operators.

The erratic IRM behavior, which is of significant amplitude only on the lower ranges (1 through 4), occurred at elevated temperatures which, during startup, are achieved only after the IRMs are on the upper ranges. Therefore, should the detector repeat this performance during startup, it would occur at a time in the IRM ranges where the IRM would not be affected. At the time of this failure, the RPS system had already performed its safety function. Had this event occurred during a controlled shutdown, the potential exists for the erratic operation of the IRMs to generate a spurious Reactor scram signal, however, the temperature range (400-500 degrees F) during which erratic behavior occurs, the reactor would normally be subcritical.

The failure of the 1A MSIV indication did not affect the consequences of the Reactor scram or recovery actions. The A MSIV line was isolated by Operator action as a precautionary action pending investigation into the cause of failure. The isolation of one steam line did not affect the ability to control Reactor pressure using the Turbine Bypass indication and required actions in the CR challenges the Operators.

The 3A and 3C CBPs' seal failure resulted in a 1-2 gallon per minute leak. These leaks were well within the capacity of the pumps to maintain adequate RFP auction pressure.

During the inspection of the CBP impeller wear rings it was noticed that the three screws that hold the impeller wear ring, were missing from the outboard rings from both the 3A and 3B CBPs. A total of six screws missing. Also a piece of the 3C CBP impeller wear ring, 4 inches long 1/2 inch wide and 1/8 inch thick was missing. The screws are 1/4 inches in diameter and 3/8 inches long

and are made of stainless steel. The screws are the set screw type, with no cap of larger diameter than the body of the screws.

There are two possible flow paths for the missing parts. The first is through the condensate booster piping to the Condensate Booster Minimum Flow (CBMFV) valve 3-3401, and the second is through the feedwater heaters, feedwater pumps to the Feedwater Regulating valves (FWRV) 3-642A, 3-642B or 3-643. Based on the size, geometry and material of the individual parts, there is no concern related with the various feedwater components up to the FWRVs. The missing parts should not affect any of the FWRVs or the CBMFV either. The 3A FWRV and the CBMFV are CCI Drag valves, which have a plug inside a disc stack configuration. The disc stack serves as a protective strainer, preventing particles from entering the disk stack and possibly causing damage to internal parts. The disk stack consists of a number of disks into which labyrinth flow passages have been punched, to provide a torturous path for the fluid. As there are no straight paths through the disk, the missing parts should not pass through the valves. The 3B FWRV is a Copes Vulcan valve which contains a 6 inch stroke "HUSH" trim with cage and plug assembly. The cylinder has holes with a diameter greater than the missing screws. In the event the missing parts follow the flow path to the 3B FWRV they should pass through based on the size and flow rates.

ComEd Corporate Nuclear Fuel Services (NFS) evaluated the scenario that the missing screws, the missing piece of the wear ring, and the potential wear ring filings traveled through the feedwater system to the feedwater sparger and into the annulus. The chemical interactions, fuel cladding integrity, lift probability, flow blockages, (orifice and lower tie plate blockage) and fretting damages were reviewed. The control rod interaction was evaluated and it was concluded that if the operation of a CRD were impacted by the set screws, it would be detected during either weekly CRD exercising or quarterly scram timing. NFS also evaluated the effects of these parts on the failed fuel, and it was concluded that there is no difference between rod fretting failure in the already failed rod(s) versus an intact fuel rod.

In conclusion, NFS finds that there are no nuclear safety concerns associated with operation of Dresden Unit 3 with the identified parts missing in the primary system. (Reference letters NFS:BSS 95-135, operation with six screws missing from the condensate system in Dresden Unit 3, September 1, 1995 and NFS:BSS:95-139, Operation with a piece of wear ring from a condensate pump in Dresden Unit 3, September 6, 1995).

Based on the above discussion, the overall significance of this event is considered to be moderate.

E. CORRECTIVE ACTIONS:

Nuclear Tracking System (NTS) tracking code numbers are identified as (XXX-XXX-XX-XXXXX).

LP-C Turbine

1. All ABB blades in the Unit 3 low pressure A, B, and C rotors were replaced with blades manufactured by GE prior to Unit 3 restart. Additionally, upper and lower diaphragm repairs, casing repairs and bearing and coupling

maintenance were performed. All rotors have been examined using non destructive testing and low speed balanced prior to reassembly.

2. A portable alloy separator was used in-place in the Unit 2 LP turbine hoods to determine the stellite material grade of the 19 ABB reverse engineered blades visually identified in those rotors. The inspection found that the A rotor contained 3 non-6B ABB blades, the B rotor contains 15 in Spec ABB blades, and the C rotor has one in Spec blade. All 19 blades were found to have no cracks in the stellite by NDE. Based on the above, the Unit 2 A-LP turbine rotor has been removed and the turbine end row has been rebladed with GE blades. The remaining ABB blades on the B and C rotors contain only the in Spec stellite and are deemed acceptable.

3. A turbine NDE procedure is being implemented for penetrant

tests as well as all other turbine related NDE during overhaul inspections. (249-180-95-00801S1)

Feed Water Transient

1. A design change was performed to reduce the rate of feedwater injection once level begins to recover. This change lowered the flow control initiation setpoint (the level below which full feedwater flow is commanded) from +20 inches to +0 inches (instrument zero). Upon exiting flow control, any feedwater control valve in automatic will initially reposition to 20% flow demand. If the 3B valve is in manual (the normal condition for this valve at high power settings), it will automatically close, then be released to operator control. With this change, the feedwater system will transfer to level control mode at +0 inches following a high power scram, and respond to the level setdown setpoint of 15 inches (50% of the setpoint before the scram)

SJAE Isolated

1. The Operations Field Supervisor involved was counseled and understands his failure to perform 3-way communication (prior to the SJAEs being isolated) did not meet operations standards and expectations. He has learned from this event and has amended his work practices to prevent future occurrences.

2. The operations standards and expectations have been reviewed and emphasized to all Licensed operators.

Erratic IRM Response

1. IRM 13 has been replaced. Water was identified inside the connector cover. Drying and cleaning the connectors and cables did not provide satisfactory results, thus the IRM detector was replaced.

2. IRM 14 was inspected and found to be performing satisfactory.

3. IRM 15 was inspected and found to be performing satisfactory.

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4. IRM 16 was inspected. Water was identified inside the

connector cover. The water was removed and the connectors and cables were cleaned and dried. IRM 16 is now performing satisfactory.

5. The water intrusion will require further troubleshooting and evaluation to determine the root cause, if possible. (249-180-95-00802S1)

6. IRMs 14 and 15 will be monitored for any further erratic behavior during startup from the current Unit 3 forced outage (D3F18) and shutdowns between D3F18 and the next Unit 3 refueling outage (D3F14). Currently, there is not enough data to warrant further action. The erratic behavior is limited to a narrow range of temperature and presently does not effect operability. (249-180-95-00803S1)

7. An operability assessment was performed for the 4 IRMs prior to the Unit 3 restart which has concluded the spiking observed would not affect the safety function of the IRM's.

3-203-1A MSIV Dual Indication

1. The proper setting techniques for the 1A and 1B Limit Switches on MSIVs was reviewed and emphasized to the Electrical Maintenance Department on June 7, 1995.

2. The remaining MSIVs on Unit 3 have been inspected by System Engineering for similar problems.

3. The MSIVs on Unit 2 will be inspected by System Engineering for similar problems. (249-180-95-00804)

4. The 3-203-1A MSIV Limit Switch 1A incorrect setting was corrected.

5. Since the MSIVs' limit switches were last adjusted, during the previous refuel outage, the Electrical Maintenance Department has received additional training on the setting of limit switches. This training included the personnel performing the limit switch adjustment on a new training model using Dresden Electrical Procedure (DES) 0200-38, MSIV Limit Switch Adjustment and Scram Setpoint Check.

Condensate Booster Pumps

1. All four seals have been replaced with new or rebuilt seals.

2. The impeller wear rings have been repaired on CBPs 3A, 3B, and 3C. The new impeller wear rings have been installed using radial installed 1/4 inch 20 stainless steel cap screws. The installation of the radial cap screws will improve the chances that the wear rings will remain in place during dead head operation.

3. Dresden General Procedure (DGP) 02-03, Unit 2/3 Reactor Scram, has been revised to provide steps to establish minimum flow for the Condensate Booster Pump as soon as possible after a Reactor scram.

4. The improvements which have been made to the Feedwater system minimize the potential for simultaneous RFP trips and the resultant dead heading of the suction lines.

F. PREVIOUS OCCURRENCES:

LER/Docket Numbers Title

94-005/050237 Manual Reactor Scram Due to Loss Of Instrument Air

Upon a manual scram due to lose of Instrument Air, Vessel level increased above the HPCI nozzle and water entered the HPCI steam lines. The Feedwater Control System appeared to function properly. The RFP high level trip setpoints were re-evaluated and were changed to a lower value.

Note: The following events were identified during a partial review the TADS. The review searched for those events in which the TADS mid-range reactor level indicator showed the reactor level reaching or exceeding 60 inches above instrument zero.

93-014/050249 Reactor Scram Due to Main Condenser Low Vacuum

Upon an automatic scram due to Main Condenser low vacuum, reactor water level trended off scale of the mid-range TADS reactor level indicator (at 60 inches). The level transient and the potential for water entering the HPCI steam line were not addressed in the LER.

92-021/050249 Unit 3 Scram Due to Loss of 3B Condensate/Condensate Booster Pump

Upon an automatic scram due to Reactor low level, a level transient occurred and reactor water level trended off scale of the mid-range TADS reactor level indicator (at 60 inches). The causes were attributed to the control system's response to small signal errors and equipment problems. Corrective actions included: RFP flow setpoint was lowered to 4.9 Mlb/hr, and equipment problems were repaired. The potential for water entering the HPCI steam line was not addressed in the LER.

92-025/050249 Unit 3 Scram Due to Invalid Turbine Vibration Trip Signal

Upon an automatic scram due to an invalid main turbine vibration signal, a level transient occurred and reactor water level trended off scale of the mid-range TADS reactor level indicator (at 60 inches). The level transient was attributed to the lockout of the 3A FWRV caused by electrical noise induced into the control

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circuitry. corrective action was to improve the electrical shielding of the 3A FWRV. The potential for water entering the HPCI steam line was not addressed in the LER.

G. COMPONENT FAILURE DATA:

Manufacture Nomenclature Model/Part Number

Burgmann Pump Seal 02-SH75/146EX1

Reuter Stokes IRM

Ingersoll- Rand Impeller asmeb. 635034

A search of the NPRDS data base found one event in which the cause of the seal failure was due to system overload with the corrective action of replacing the seals. other seal failures identified were attributed to normal wear, over heating, excessive thrust, seal damage, improper maintenance, and operator error. IRM failures identified were attributed to defective circuit, metal filings, dirty contacts, unknown, noise, improper grounding, and bent pine on signal cables.

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Commonwealth Edison Company
Dresden Generating Station
6500 North Dresden Road
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ComEd

September 22, 1995

TPJLTR 95-0116

U.S. Nuclear Regulatory Commission
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Licensee Event Report 95-008, Revision 1, Docket 50-249 is being submitted pursuant to 10CFR50.73(a)(2)(iv), any event or condition that results in manual or automatic actuation of any Engineered Safety Feature (ESF), including the Reactor Protection System (RPS).

This supplement is being provided to update the results of the scram investigation and list components which failed as a result of the event.

Sincerely,

Thomas P. Joyce
Site Vice President

TPJ/:pt

Enclosure

cc: H. Miller, Regional Administrator, Region III
NRC Resident Inspector's Office
File/NRC
File/Numerical

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